BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF HAWAII

In the Matter of PUBLIC UTILITIES COMMISSION Instituting a Proceeding to Investigate Implementing a Decoupling Mechanism for Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., and Maui Electric Company, Limited	DOCKET NO. 2008-0274

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PUBLIC UTILITIES COMMISSION

BLUE PLANET FOUNDATION'S RESPONSE TO INFORMATION REQUESTS FROM THE COMMISSION'S CONSULTANT, NATIONAL REGULATORY RESEARCH INSTITUTE, DATED JULY 15, 2009

AND

CERTIFICATE OF SERVICE

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Blue Planet Foundation ("Blue Planet"), by and through its attorneys Schlack Ito Lockwood Piper & Elkind, hereby responds to the Information Requests from the Commission's Consultant, National Regulatory Research Institute, dated July 15, 2009.

IRs for All Parties

PUC-IR-56

7. **Please discuss the success and failures of decoupling in other jurisdictions (e.g., Maine).**

RESPONSE:

The experience in Maine suggests decoupling may be successful in Hawaii to the extent the benefits of decoupling to the utilities are clearly linked to utility performance and achievement of Hawaii energy law and policy goals, including the Hawaii Clean Energy

Initiative ("HCEI") and Energy Agreement.[1] Strong public support exists for advancing Hawaii's clean energy goals and reducing the billions of dollars spent annually on imported fossil fuels. To the extent the public understands and views decoupling as an integral part of broad efforts to achieve the HCEI goals, and lower Hawaii's high energy costs over the long run, decoupling may avoid some of the difficulties encountered in Maine.

Although many other jurisdictions have successfully implemented decoupling,[2] Maine's experience with revenue decoupling is generally considered a failure.[3] In 1991, the Maine Public Utilities Commission adopted a revenue decoupling mechanism ("ERAM") for Central Maine Power ("CMP"). The allowed revenue was determined in a traditional rate case proceeding and adjusted annually based on changes in the utility's number of customers. Around the time ERAM was adopted, Maine experienced a major recession that resulted in lower sale levels and approximately $52 million in revenue deferrals which CMP was entitled to recover from ratepayer surcharges. Because a very small amount of revenue deferrals was due to CMP's conservation efforts as compared to the recession, the public viewed ERAM as a mechanism that protected CMP against the economic impact of the recession instead of providing CMP with energy efficiency and conservation incentives. The ERAM was terminated by agreement on November 30, 1993, because it failed to encourage CMP to promote energy efficiency and conservation and to protect ratepayers from high costs.[4]

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[1] *Energy Agreement Among the State of Hawaii, Division of Consumer Advocacy of the Department of Commerce and Consumer Affairs, and the Hawaiian Electric Companies* dated Oct. 20, 2008 ("Energy Agreement").

[2] For example, four utilities in California (Pacific Gas & Electric, Southern California Edison, San Diego Gas & Electric, and Pacific Power & Light) operate under decoupling. "Revenue Decoupling for Hawaiian Electric Companies," Pacific Economics Group, LLC (Feb. 3, 2009) ("PEG Report") at 22, attached as Attachment 1 to Letter from D. Matsuura (HECO) to Commission dated Feb. 24, 2009.

[3] Maine Public Utilities Commission, *et al.*, "Report on Revenue Decoupling for Transmission & Distribution Utilities" at 10, *available at* http://www.maine.gov/mpuc/legislative/archive/2006legislation/decouplingrptfinal.doc.

[4] *Id.*

Decoupling is generally promoted as a means of reducing utility disincentives toward energy efficiency and increased use of renewable energy. The Energy Agreement, for example, states that decoupling may facilitate Hawaii's transition to a clean energy future by removing barriers for the utilities to pursue aggressive demand-response and load management programs and customer-owned or third-party-owned renewable energy systems while giving the utilities an opportunity to achieve fair rates of return.[5] The Commission's Scoping Paper[6] similarly affirms that decoupling is any mechanism that "breaks the link" between sales and earnings to eliminate the financial penalty incurred by utilities through cost-effective programs that reduce sales.[7] The PEG Report submitted by the HECO Companies[8] and Consumer Advocate[9] in support of their decoupling proposal concludes that "[d]ecoupling is a part of a package of incentives that can induce electric utilities to aggressively promote DSM [demand side management]."[10] The report concludes decoupling "will help to align the interests of the HECO Companies with those of customers, state policymakers, and DSM and DG advocates."[11]

In Hawaii, although decoupling may be required to maintain the utilities' financial integrity, the disincentives-reduction rationale assumes somewhat less importance because although the HECO Companies will continue to play an important role in DSM and distributed generation, many DSM programs in Hawaii are undertaken by independent agencies (i.e., Public Benefits Fee Administrator SAIC).[12] Thus, in addition to focusing on reducing disincentives to

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5 Energy Agreement at 32.

6 "Decoupling Utility Profits from Sales: Design Issues and Options for the Hawaii Public Utilities Commission" (National Regulatory Research Institute, January 2009) ("Scoping Paper").

7 *Id* .at 2.

8 Hawaiian Electric Company, Inc.; Maui Electric Company, Limited; and Hawaii Electric Light Company, Inc.

9 State of Hawaii Department of Commerce and Consumer Affairs Division of Consumer Advocacy ("Consumer Advocate")

10 "Revenue Decoupling for Hawaiian Electric Companies," Pacific Economics Group, LLC (Feb. 3, 2009) at 44, attached as Attachment 1 to Letter from D. Matsuura (HECO) to Commission dated Feb. 24, 2009.

11 PEG Report at 53.

12 *Id.* at 52.

DSM and maintaining the utilities' financial integrity, decoupling in Hawaii may properly emphasize increasing utility incentives to achieve energy efficiency and renewable energy requirements established by Hawaii energy law and policy. In this proceeding, it is has been suggested that decoupling should incorporate a performance incentive mechanism.

Analysis of the Maine experience supports incorporation of a performance incentive mechanism in any decoupling mechanism adopted in this proceeding. Support for ERAM in Maine was weakened when some of the supporters of ERAM perceived the utility as not working toward achieving the energy policy goals.[13] These supporters, and members of the public, began to view ERAM as "a comfortable but unmerited cushion during hard economic times."[14] To avoid this public perception, decoupling in Hawaii should include a relatively simple and clear link between the benefits of decoupling to the utilities and achievement of HCEI objectives, which can be effectively communicated to the public.[15]

Finally, as further explained in response to PUC-IR-60, below, the Maine experience also supports the establishment of a relatively lower Allowed Return on Equity which recognizes that a utility faces no prudence review or regulatory scrutiny of its operating expenses or plant additions in the proposed Revenue Adjustment Mechanism ("RAM"). As compared to traditional ratemaking, a RAM may effectively transfer a significant amount of risk from the HECO Companies to its customers, or reduce or eliminate such risk.

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[13] L. Hudson, S. Seguino, and R. Townsend, "Maine's Electric Revenue Adjustment Mechanism: Why It Fizzled," *The Electricity Journal* (Oct. 1995) at 81.

[14] *Id.*

[15] The PEG Report identifies Washington State as an example of successful use of decoupling mechanism to achieve energy policy goals. PEG Report at 40. Decoupling played a "critical role" in encouraging "dramatic improvements" and the achievement of the primary goal of Puget Sound Energy's energy efficiency and conservation goals, resulting in the utility developing a distinguished reputation and becoming a national leader in the area of energy efficiency and conservation. *Id.*

PUC-IR-57

8. Please discuss the pros and cons of implementing the revenue enhancements discussed at each 3a, b, c, and d of the Commission's post-hearing IRs.

RESPONSE:

As a preliminary matter, the following general principles and comments are offered with regard to Commission determination of an inter-rate case revenue enhancement mechanism for the HECO Companies:

- Calculation of any inter-rate case revenue enhancement should reflect, as much as possible, the methodology used by the Commission in a traditional rate case to determine a particular component of an electric utility's revenue requirements.
- Reducing the frequency and number of rate case filings may allow the HECO Companies to direct institutional resources from such filings toward efforts to achieve Hawaii energy law and policy objectives, including HCEI and Energy Agreement commitments.
- Regulatory lag should be reduced to the extent possible. In that regard, it may be advantageous for the HECO Companies to accept rate relief in an amount slightly lower than required, if the relief is available in a more timely manner due to reduced regulatory lag.
- The number and frequency of rate case filings may increase to the extent various revenue requirement components are excluded from any RAM adopted in this proceeding (e.g., exclusion of a portion of plant additions, exclusion of non-HCEI O&M expenses, etc.), and may decrease to the extent they are included in the RAM. If the Commission adopts a comprehensive RAM that incorporates all revenue requirement components sought by the HECO Companies, and the RAM

effectively removes regulatory lag, the Commission should consider imposing a moratorium on future rate case filings (with appropriate provisions made for *force majeure* circumstances).

- Annual revenue increases based upon RAM formulas should be roughly equivalent to annual revenue increases the HECO Companies would obtain by means of a traditional rate case, as adjusted to reflect the lack of regulatory prudency review and avoidance of regulatory lag. In effect, the Commission should seek to adopt a "breakeven" RAM revenue level sufficient to enable the HECO Companies to forego traditional rate case filings for a three to four year period. It appears that the effective "breakeven" annual RAM revenue level for HECO may be approximately $30 million, based upon 2005, 2007, 2009 test year interim rate increases.[16] It may be necessary and appropriate for this amount to increase over the next five years.[17]
- It is appropriate for Return on Equity ("ROE") sharing, as proposed in the Joint Decoupling Proposal,[18] to be incorporated into any RAM mechanism adopted by the Commission.
- Utility service quality standards should be incorporated as part of any RAM mechanism to insure that any measures taken by the HECO Companies to reduce

[16] The Commission has awarded HECO interim rate increases of $53, $70 and $61 million in 2004, 2006, and 2008, respectively, or a total of $184 million in interim base rate increases for an average of $60 million per rate case. If annual interim rate increases had been granted, the equivalent amount would be $30 million in additional base rate revenue per year.

[17] HECO's plant additions projected for the 2009-13 period are significantly higher than the actual plant additions made during the 2004-08 period. *See* HECO Companies' Response to PUC-IR-52 at Attachment 2, p. 1.

[18] *See* Joint Proposal on Decoupling and Statement of Position of the HECO Companies and the Consumer Advocate filed Mar. 30, 2009 at 16-18; Joint Final Statement of Position of the HECO Companies and Consumer Advocate filed May 11, 2009 ("Joint Decoupling Proposal") at 18-19

O&M expense escalation and capital expenditures would not adversely affect customer service quality and reliability.

- RAM rate relief should exclude operations and management ("O&M") expenses and plant addition costs directly attributable to the HECO Companies efforts to achieve the requirements of Hawaii energy law and policy, including the Hawaii Clean Energy Initiative ("HCEI") and Energy Agreement. Cost recovery for HCEI-related items – O&M expenses and capital additions – should be made through the Renewable Energy Infrastructure Program ("REIP") and/or the Clean Energy Infrastructure Surcharge ("CEIS") mechanisms. The RAM should be implemented to improve and then maintain the HECO Companies' financial integrity. To facilitate Commission evaluation of whether and to what extent the RAM has contributed to the HECO Companies' financial integrity, and is therefore an effective and valuable alternative to traditional ratemaking, RAM revenue requirements and HCEI-related revenue requirements should not be conjoined.

With regard to pros and cons of implementing the revenue enhancements discussed at 3a, b, c, and d of the Commission's post-hearing IRs, the following comments and observations are offered:

- Items 3a – 3f vary principally in the extent to which individual revenue requirement components are eligible for inclusion in the RAM rate adjustment.
- Quarterly implementation of a capital additions component to the RAM may reduce regulatory lag and may allow the use of an actual plant-related balances based upon quarterly financial data. It may be possible for the rate base RAM

formula set forth in the Joint Decoupling Proposal to be converted from its current annual projected net plant additions construct to a quarterly actual net plant addition mechanism.

- It appears that an annual RAM rate increase tied solely to fixed costs (return on net plant additions and depreciation of gross plant additions), whether pursuant to the HECO Companies' RAM rate base proposal or items 3a and b, excluding O&M expense increases, and as calculated over the previous five-year period,[19] would be unlikely to produce annual RAM rate adjustments for HECO greater than traditional rate increases. Whether such a RAM would do so in the future depends upon the utilities' ability to control and manage O&M expense levels and future capital expenditures.
- Based upon cost trends over the previous five-year period, it appears total O&M expenses must be included in the RAM (as proposal in 3d). If HECO implemented its proposed RAM adjustment formula for O&M expenses in the past, it appears likely that the O&M-related rate increases from the RAM would have been substantially less than the actual level of O&M increases. Even assuming the foregoing, more frequent traditional rate cases filings would have been required to "reset" the O&M expense base to avoid an increasing divergence between RAM and actual O&M expense levels.
- It is possible to limit RAM fixed cost recovery to plant additions related to reliability and customer additions. This would require the HECO Companies to develop and implement processes to review and sort numerous individual capital

[19] *See* HECO Companies' Response to PUC-IR-52 at Attachment 2, p. 1.

projects into reliability and customer additions categories, in addition to the current National Association of Regulatory Commissioners ("NARUC") plant in service accounts. These processes would necessarily be designed to facilitate review and audit by the Consumer Advocate. It appears the additional time and effort necessary to classify and audit capital projects into reliability and customer addition categories may ultimately result in the removal of a relatively small amount of gross plant expenditures; it therefore may not be worthwhile to develop new plant account categorization processes.

- It is noted that 3c, directed at the incremental O&M costs associated with implementing HCEI, would allow timely (quarterly) recovery of HCEI-related costs but is not directly linked to the achievement of HCEI-related goals.

PUC-IR-58

9. Should the RAM concepts described at 3a and b be based on gross or net plant additions?

RESPONSE:

The calculation of any inter-rate case revenue enhancements should reflect, to the extent possible, the methodology used by the Commission in a traditional rate case to determine a particular component of an electric utility's overall revenue requirements. With respect to utility plant investment, the applicable components of revenue requirements are the return of plant investment (depreciation expense) and the required return on plant investment (rate base), including related income taxes. Annual depreciation expense is determined by the product of depreciable plant investment (generally gross plant excluding land) multiplied by the applicable depreciation accrual rates approved by the Commission.

Return on plant investment is determined by the product of rate base multiplied by the authorized overall rate of return plus applicable income taxes related to the equity return (net income). Rate base items related to utility plant in service (excluding working capital and regulatory asset items) are based upon plant in service funded by "investor capital," and are generally determined by subtracting "customer provided capital" (i.e., accumulated depreciation expense, accumulated CIAC and accumulated deferred income taxes) from gross plant in service.

The annual revenues additions submitted by the HECO Companies in their response to items 3a and b would appear to overstate the annual change in the overall revenue requirements associated with these utility plant investment categories. A utility plant related inter-rate case revenue enhancement, or RAM, based solely on gross plant additions as a proxy for rate base changes, fails to account for the annual decline in existing plant in service (rate base) due to the on-going depreciation of existing plant in service. Simply stated, it is the annual net plant additions (gross plant additions minus the depreciation expense on existing plant in service) that determine the need for additional return on investment and related income taxes, not gross plant additions. The latter should be used solely to determine the increase in annual depreciation expense.

PUC-IR-59

10. Please propose allocation methods among customer classes for each 3a, b, c and d and explain the basis for the allocation.

RESPONSE:

The methodology used to allocate sales decoupling and RAM adjustments to customer classes should reflect, to the extent possible, the methodology used by the Commission in a traditional rate case to allocate revenue requirements among customer classes. Sales decoupling and RAM rate adjustment mechanisms merely mechanize portions of the traditional rate case process. Simplifying assumptions should be utilized to approximate the rate case methodology in order to avoid the necessity of performing a detailed cost of service study as part of the annual sales decoupling and RAM filing. A uniform per KWh surcharge method should be used to allocate annual sales decoupling and RAM rate adjustments, including for items 3a, b, c and d, for the reasons explained below.

The sales decoupling rate adjustment should be determined on a total company basis, not on a customer class basis. Unless the rate is determined on a total company basis, the resulting rates to customers adjusted via sales decoupling may diverge from rates that would be revised in a general rate case had the revenue adjustment due to a sales level change been implemented through a rate case. This would occur because base rate revenues (non-fuel and purchased power) are determined on a total company basis first in a rate case, and subsequently allocated to customer classes based on their current relative, proportional energy use and the demand characteristics of each customer class.

Stated differently, base revenue requirements are not fixed for individual customer classes. They are fixed on a total company basis and then are allocated to customer classes by relative, proportional energy usage characteristics of each customer class. Therefore, if the energy use characteristics of a customer class change, then the proportion of the total base revenue requirements (non-fuel and purchased power) for which the customer class would be responsible would also change.

The HECO Companies' propose to determine a sales decoupling rate adjustment separately for residential and non-residential customer categories and collect/refund the rate adjustment entirely within the respective customer classes. As such, HECO's decoupling proposal would not reflect changed customer class energy usage characteristics and thus how such sales change rate adjustments would be allocated to customer classes in a traditional rate case. Attachment 1 provides an illustrative comparison of HECO's sales decoupling allocation proposal versus that which would occur in a traditional rate case cost of service class allocation. The HECO Companies' proposal would:

- Allocate a rate increase due to class sales reduction solely to the customer class which experienced the sales reduction. This is contrary with that which would occur in a rate case utilizing traditional cost of service methodology, as shown in Attachment 1.
- Conversely, allocate a rate decrease due to class sales increase solely to the customer class which experienced a sales increase. Again, this is inconsistent with that which would occur in a rate case utilizing traditional cost of service methodology.

The more appropriate method would be to determine the sales decoupling adjustment on a total company basis and then utilize a uniform per KWh surcharge to allocate the decoupling rate adjustment to customer classes. A uniform per KWh sales decoupling rate adjustment, determined on a total company basis, would closely approximate how base rate revenue requirements would be re-allocated in a rate case to various customer classes when a customer class' energy use characteristics have changed. This is illustrated in Attachment 2. It also would avoid "penalizing" a customer class that reduces its energy use.

Annual RAM rate adjustments should be determined on a total company basis and then allocated on current, not historic, energy usage characteristics. The HECO Companies' proposal is to use the allocation factors from the last rate case to apportion the RAM rate adjustment, which is determined on a total company basis, to customer classes. The HECO

Companies' approach to the allocation of the RAM rate adjustment would approximate the results achieved in a rate case only if a customer class' energy usage characteristics does not deviate from its historical relative proportion of total system energy usage. If the relative energy usage proportion of a class changes, the HECO Companies' allocation method would deviate from that which would result from a rate case cost of service study, as shown in Attachment 3.

Alternatively, and consistent with the preferred allocation method for sales decoupling, the RAM rate adjustment could be allocated to customer classes on the basis of a uniform per KWh surcharge. Although a uniform per KWh surcharge is to a large extent an energy allocation approach, it is typical for most utilities (including the HECO Companies) that energy and demand allocation prorations for major customer classes are very similar. Because of this fact, a uniform per KWh surcharge method is a reasonable proxy for demand allocation factors and thus could be used for both RAM and sales decoupling rate adjustments. It would also simplify the sales decoupling and RAM annual filing process.

The utilization of a uniform per KWh surcharge to allocate both RAM and sales decoupling rate adjustments to customer classes would also approximate the results that would be obtained from a rate case cost of service study involving changes in a customer class' relative proportion of total energy usage as shown on Attachment 4. The use of a uniform per KWh method to allocate costs is simple, straightforward and produces results that are consistent with those obtained from traditional cost of service studies utilized in a rate case.

PUC-IR-60

11. What should the Commission consider in selecting an ROE to use in calculating revenue enhancements between rate cases associated with rate base changes. Why should the ROE used in calculating the inter-rate case revenue adjustments based on rate base changes be equal to the ROE authorized in the rate case (per the proposed RAM), as the inter-rate case ROE appears to be guaranteed and the rate

case ROE is an opportunity to earn the authorized return? Please discuss and quantify.

RESPONSE:

Although it may appear that sales decoupling and RAM effectively guarantee an inter-rate case ROE, they guarantee only collection of the rate case base revenues (non-fuel and purchased power) and RAM revenues. Actual ROE is determined by the actual level of accounting net income, which is the difference between utility revenues received (guaranteed) and the actual utility operating expense levels (not guaranteed). The actual amount of a utility's operating expenses in any year is not guaranteed because the utility's actual O&M expense may or may not be the same as that assumed in the revenue requirements used to establish base rates in the prior rate case. In addition, the annual increase in utility operating expenses and net rate base may not be identical to that calculated by the various escalation formulas in the RAM.

Notwithstanding the foregoing, it may be appropriate for the Commission to employ a relatively lower ROE to calculate the RAM rate base revenue adjustment insofar as, with a RAM, the a utility faces no prudence review or regulatory scrutiny of its operating expenses or plant additions in the proposed RAM mechanism. Moreover, as compared to traditional ratemaking, a RAM may effectively transfer a significant amount of risk from the HECO Companies to its customers. The RAM may also reduce or eliminate such risk. The HECO Companies' business risk and cost of equity capital will likely be reduced to the extent the Commission implements sales decoupling and a RAM.

As the question suggests, the lower cost of equity capital could be incorporated into the RAM rate base calculation. However, this would limit the application and customer benefit of the lower cost of equity capital to only the incremental net additions to rate base. The resulting incremental RAM rate base revenue impact would likely be very small in comparison to the amount of risk transferred from the HECO Companies to their customers. It may therefore be more appropriate to apply the lower cost of equity capital to the entire utility net rate base by applying the lower ROE in a rate case. The lower rate case ROE should also be applied in the RAM rate base adjustment formula.

Finally, it is noted that decoupling may entail a potential unintended consequence. If ROE is reduced, the HECO Companies' potential level of future profitability may be reduced correspondingly at the same time the utilities seek to achieve the HCEI and Energy Agreement objectives. In the event the Commission reduces the HECO Companies' ROE in a rate case to reflect the lower cost of equity capital, it may be appropriate for the HECO Companies to have recourse to a performance incentive mechanism as may be adopted by the Commission. Such a mechanism may allow the HECO Companies to restore and increase profits based upon their successful achievement the Hawaii clean energy law and policy objectives.

PUC-IR-61

12. Please discuss the pros and cons of the Commission approving a RAM that consists of 3a, b and c with and without an RPC compared to the RAM proposed by HECO.

RESPONSE:

The following general observations and comments are offered relative to a comparison between the RAM proposed by HECO and revenue enhancements 3a, b and c with and without a Revenue Per Customer ("RPC").

The RAM proposed in the Joint Decoupling Proposal consists of both an O&M expense and rate base (plant) component. The latter component is designed to estimate the annual change in plant related revenue requirements for net plant additions (all plant items, rather than reliability or customer addition plant). O&M expense increases are determined by a formula that is applied to all O&M expenses not subject to an automatic adjustment clause (e.g., pension, Other Post Employment Benefits ("OPEB"), Integrated Resource Planning ("IRP"), etc.).

Revenue enhancement items 3a, b and c consist of a partial rate base component and a limited O&M expense component (HCEI-related items only). The rate base component is only applicable to reliability and customer gross plant additions. Based on the information submitted by the HECO Companies in response to items 3a and 3b, these plant additions represent a significant amount of the total historical and forecast gross plant additions.

Item 3c is proposed to apply only to O&M expenses related to implementation of Act 155.[20] These items would appear to represent one time or non-continuing multi-year expenses better suited for recovery through a program specific surcharge mechanism, such as the Renewable Energy Infrastructure Program ("REIP") and/or the Clean Energy Infrastructure Surcharge ("CEIS"). Revenue enhancements for the mechanisms proposed in items 3a, b and c would be implemented on a quarterly basis, presumably based on actual in service plant balances and actual HCEI-related expenses.

With respect to plant investment, the principle differences appear to be:

- RAM would be developed annually based on projected net rate base which consists of baseline gross plant additions minus the projected increases in accumulated depreciation, CIAC and deferred taxes, and any major projects that are expected to be placed in service by September of the RAM period (test year).
- Items 3a and b would be developed quarterly, presumably based upon the trailing quarterly actual gross plant balances for reliability and customer addition projects. This methodology would exclude some plant additions and would ignore the continual reductions to the existing net rate base due to annual increases in

[20] 2009 Haw. Sess. Laws, Act 155 § 1; H.B. 1464, 25th Leg. (Haw. 2009).

accumulated depreciation – the latter rate base reduction could be larger than the former unrecovered plant additions.

- Item 3c would enable the recovery of one-time HCEI-related O&M expenses but not enable the recovery of on-going (non-HCEI) O&M expenses, likely necessary to ensure the HECO Companies' financial integrity.
- Although it is difficult to directly compare inter-rate case revenue streams, it appears items 3a, b and c would produce a slightly higher ROE than the Joint Decoupling Proposal's rate base and O&M RAM. The annual revenue streams for items 3a and b, as calculated by the HECO Companies, would overestimate the required annual change in plant related revenue requirements because the annual decline in existing rate base, and required return on investment, due to the continued depreciation of existing plant was not used to offset the revenue requirements impact of gross plant additions.

Finally, incorporating a RPC, either with or without reset, with any RAM including those proposed by items 3a, b and c, may result in double recovery of certain revenue requirements items. In practice, it may be difficult to measure the exact amount of any such double recovery and reduce the RAM rate increase by a corresponding amount.

PUC-IR-62

13. Please discuss the pros and cons of an ECAC in which (a) the utility bears the risk for heat rate changes within a performance band (e.g., plus/minus 50 Btu from the target) while (b) all changes in costs associated with heat rate changes outside the performance band are passed through to customers.

RESPONSE:

Eliminating the fixed heat rate efficiency component of the ECAC mechanism may remove a disincentive for the HECO Companies to integrate additional renewable energy resources onto the grid. Adoption of the suggested heat rate performance band within which the HECO Companies would be financially at risk for changes in power plant heat rate may not remove the renewable energy resource integration disincentive, and could potentially encourage outcomes that would not be in the interest of ratepayers. For example, if plant heat rate performance deteriorates (regardless of the reason), it is possible the HECO Companies may allow performance to continue to deteriorate until performance falls outside the performance band, thereby avoiding a ECAC heat rate performance penalty. If this occurs, although the utility avoids a financial penalty ratepayers pay higher fuel costs insofar as the plant heat rate deteriorates to a greater degree than it would have in the absence of a performance mechanism "cliff."

The plus/minus 50 Btu heat rate performance band is the opposite of the performance band proposed by the HECO Companies. They proposed a deadband under which no reward or penalty would be triggered if plant performance remained within the performance deadband range. Such a proposal excludes a performance "cliff" and the attendant undesired outcomes.

Data concerning HECO's recent heat rate performance, as shown in the table below, suggest annual fluctuations may often fall outside of a plus/minus 50 Btu performance band.

	HECO Central Station Steam Generation					
	2003	**2004**	**2005**	**2006**	**2007**	**2008**
Generation Output (GWh)	4,652	4,882	4,689	4,833	4,828	4,659
Heat Rate (BTUs/KWh-Gen)	10,413	10,540	10,620	10,540	10,583	10,468
Heat Rate Change (BTUs/KWh-Gen))		127	80	(80)	43	(115)
Source: HECO FERC Form 1						

PUC-IR-63

14. Please discuss the pros and cons of an ECAC that remained the same as the current ECAC but removed the Btus used for spinning reserve from the heat rate calculation.

RESPONSE:

As a practical engineering matter, it is not possible to measure the quantity of Btus used for spinning reserves. The reason is that no Btus are consumed to provide spinning reserves. Spinning reserves are provided by generating units already on-line which are producing electricity at less than their full rated capacity, and therefore represent on-line, real-time stand-by capacity. By definition, there is no spinning reserve electricity being generated that would require Btus of fuel consumption.

Instead, spinning reserves may be considered a lost economic opportunity. But for the required reduction in generating unit output, the generating unit would have been producing electricity at full capacity presumably at lower overall unit cost. Spinning reserves may impact a generating unit's heat rate, not directly through the provision of spinning reserves (stand-by), but rather indirectly by affecting the heat rate at which the reduced electrical output is generated. Thus, engineering and/or system re-dispatch analyses would have to be performed to estimate the impact of spinning reserves on system heat rate.

It is noted that spinning reserve is an ancillary service provided by a generator operating at less than its full capacity. Cost methodologies have been developed to determine the cost of providing spinning reserves, as well as other ancillary services such as frequency regulation reserves and system voltage ("VAR") support. A key element in these cost studies is the explicit recognition of the economic value of the lost opportunity to produce additional electricity insofar as generating units used to provide various ancillary services are operated at less than full generating capacity.[21]

DATED: Honolulu, Hawaii, August 24, 2009.

DOUGLAS A. CODIGA
Attorney for Blue Planet Foundation

[21] It may be appropriate for the Commission to consider requiring the HECO Companies to establish tariff prices for ancillary services. Additional utilization of intermittent renewable resources will likely require additional ancillary services. Establishing prices which reflect the HECO Companies' cost to provide these ancillary services would create price signals for renewable developers and independent ancillary service providers who may wish to enter the Hawaii market based upon their ability to provide such services in a more cost-effective manner.

Customer Class Allocation
of Sales Decoupling Rate Adjustment
HECO Companies Proposal

HECO Illustrative Example

Line Number		Total Company	Residential	Non-Residential		Comments
Initial Rate Case Test Period Parameters						
1	Electric Sales Used for Rate Design (MWh)	7,500,000	2,000,000	5,500,000		Approximate total sales level and
			27%	73%		distribution by customer classes
2	Base Revenue Requirements ($000)	500,000	185,000	315,000		Interim base revenue requirements
	(Non-Fuel & Purchased Power)		37%	63%		established by PUC in 2008-0083
3	Average Base Revenue Req Rate (¢/KWh)	6.67	9.25	5.73		Line 2 divided by Line 1
	Current Cost of Service Overall Allocation Factors					
4	Sales (Energy Related Costs)		27%	73%		Calculated from data supplied in
5	Demand (Demand Costs)		29%	71%		Attachment 4, WP-4a. Page 1 of 1
6	Customer (Overall Customer Costs)		72%	28%		to HECO's response to questions
7	Fixed Costs (Combined Demand & Customer)		37%	63%		from Decoupling Panel Hearing
8	Ratio Fixed Costs/Sales Allocation		1.39	0.86		Line 7 divided by Line 4
Subsequent Sales Decrease -- Sales Decoupling (HECO Companies Proposal)						
9	Actual Electric Sales (MWh)	7,300,000	1,800,000	5,500,000		Assume 10% residential sales drop
10	Percent Sales Change	-2.7%	-10.0%	0.0%		
11	Actual Base Revenue Collected ($000)	481,500	166,500	315,000		Line 9 x Line 3
	Sales Decoupling Mechanism					
12	Decoupling Revenue Adjustment ($000)		18,500	0		Line 2 - Line 11
13	New Sales Level (MWh)		1,800,000	5,500,000		Line 9
14	Decoupling Rate Surcharge (¢/KWh)		1.03	0.00		Line12 divided by Line13
15	Decoupling Revenue Increase ($000)	18,500	18,500	0		Line 14 x Line 9
16	Revised Class Base Revenues ($000)	500,000	185,000	315,000	<=	Line 11 + Line 15
					=	
	New Customer Rates (¢/KWh)				=	
17	Existing Base Rate	6.60	9.25	5.73	=	Line 11 divided by Line 9
18	Decoupling Rate Surcharge	0.25	1.03	0.00	=	Line 15 divided by Line 9
19	Total	6.85	10.28	5.73	=	Line 17 + Line 18
					=	
20	Percent Rate Increase	3.8%	11.1%	0.0%	=	Line 18 divided by Line 17
					=	
					=	
Subsequent Sales Decrease -- New Rate Case					=	
21	Actual Electric Sales (MWh)	7,300,000	1,800,000	5,500,000	=	Line 9
			25%	75%	=	
	Cost of Service Proxy Allocation				=	
22	Sales Allocation	100%	25%	75%	=	Line 21
23	Ratio Fixed Costs/Sales Allocation		1.39	0.86	=	Line 8
24	Fixed Costs (Combined Demand & Customer)		34%	66%	=	Line 23 x Line 22
					=	
	Revised Class Base Revenues ($000)				=	
25	Customer Class Allocation	500,000	171,062	328,938	<=	Line 24 x line 25
						Rate case results differ substantially
26	New Base Rates (¢/KWh)	6.85	9.50	5.98		from sales decoupling results
						[Line 25 differs from Line 16]
27	Percent Rate Increase	3.8%	2.7%	4.4%		

Customer Class Allocation
of Sales Decoupling Rate Adjustment
Uniform per KWh Surcharge Method

Attachment 2

HECO Illustrative Example

Line Number		Total Company	Residential	Non-Residential		Comments
Initial Rate Case Test Period Parameters						
1	Electric Sales Used for Rate Design (MWh)	7,500,000	2,000,000	5,500,000		Approximate total sales level and
			27%	73%		distribution by customer classes
2	Base Revenue Requirements ($000)	500,000	185,000	315,000		Interim base revenue requirements
	(Non-Fuel & Purchased Power)		37%	63%		established by PUC in 2008-0083
3	Average Base Revenue Req Rate (¢/KWh)	6.67	9.25	5.73		Line 2 divided by Line 1
	Current Cost of Service Overall Allocation Factors					
4	Sales (Energy Related Costs)		27%	73%		Calculated from data supplied in
5	Demand (Demand Costs)		29%	71%		Attachment 4, WP-4a. Page 1 of 1
6	Customer (Overall Customer Costs)		72%	28%		to HECO's response to questions
7	Fixed Costs (Combined Demand & Customer)		37%	63%		from Decoupling Panel Hearing
8	Ratio Fixed Costs/Sales Allocation		1.39	0.86		Line 7 divided by Line 4
Subsequent Sales Decrease -- Sales Decoupling (Uniform per KWh Surcharge Method)						
9	Actual Electric Sales (MWh)	7,300,000	1,800,000	5,500,000		Assume 10% residential sales drop
10	Percent Sales Change	-2.7%	-10.0%	0.0%		
11	Actual Base Revenue Collected ($000)	481,500	166,500	315,000		Line 9 x Line 3
	Sales Decoupling Mechanism					
12	Decoupling Revenue Adjustment ($000)	18,500				Line 2 - Line 11
13	New Sales Level (MWh)	7,300,000				Line 9
14	Decoupling Rate Surcharge (¢/KWh)	0.25	0.25	0.25		Line12 divided by Line13 and applied
						to each rate class
15	Decoupling Revenue Increase ($000)	18,500	4,562	13,938		Line 14 x Line 9
16	Revised Class Base Revenues ($000)	500,000	171,062	328,938	<=	Line 11 + Line 15
					ll	
	New Customer Rates (¢/KWh)				ll	
17	Existing Base Rate	6.60	9.25	5.73	ll	Line 11 divided by Line 9
18	Decoupling Rate Surcharge	0.25	0.25	0.25	ll	Line 15 divided by Line 9
19	Total	6.85	9.50	5.98	ll	Line 17 + Line 18
					ll	
20	Percent Rate Increase	3.8%	2.7%	4.4%	ll	Line 18 divided by Line 17
					ll	
					ll	
Subsequent Sales Decrease -- New Rate Case					ll	
21	Actual Electric Sales (MWh)	7,300,000	1,800,000	5,500,000	ll	Line 9
			25%	75%	ll	
	Cost of Service Proxy Allocation				ll	
22	Sales Allocation	100%	25%	75%	ll	Line 21
23	Ratio Fixed Costs/Sales Allocation		1.39	0.86	ll	Line 8
24	Fixed Costs (Combined Demand & Customer)		34%	66%	ll	Line 23 x Line 22
					ll	
	Revised Class Base Revenues ($000)				ll	
25	Customer Class Allocation	500,000	171,062	328,938	<=	Line 24 x line 25
						Rate case results are equivalent to
26	New Base Rates (¢/KWh)	6.85	9.50	5.98		sales decoupling results [Line 25 is
						equal to Line 16]
27	Percent Rate Increase	3.8%	2.7%	4.4%		

Customer Class Allocation
of Sales Decoupling and RAM Rate Adjustments
HECO Companies Proposal

Attachment 3

HECO Illustrative Example

Line Number		Total Company		Residential		Non-Residential		Comments
Annualt RAM Rate Adjustment -- Different Class Sales Levels (HECO Companies Proposal)								
1	Actual Electric Sales (MWh)	7,300,000		1,800,000		5,500,000		From Attachment 1, Line 9
	Rate Adjustment Mechanism ($000)							
2	O&M Expense Increase	5,000						Consistent with HECO/CA
3	Rate Base Related Adjustment	20,000						illustrative RAM calculations for 2010
4	Total RAM Revenue Adjustment	25,000						
	Allocation of RAM Rate Adjustment							
5	RAM Revenue Adjustment ($000)	25,000						
								Previous rate case allocation from
6	RAM Rate Allocation	100%		37%		63%		Attachment 1, Line 2
7	RAM Revenue Increase ($000)	25,000		9,250		15,750		Line 5 x Line 6
	Revised Class Revenues ($000)							
8	Base Revenues After Sales Decoupling	500,000		185,000		315,000		From Attachment 1, Line 16
9	RAM Revenue Increase ($000)	25,000		9,250		15,750		Line 7
10	Total	525,000		194,250		330,750	<=	Line 8 + Line 9
							॥	
	New Customer Rates (¢/KWh)						॥	
11	Total Rate after Decoupling	6.85		10.28		5.73	॥	Line 8 divided by Line 1
12	RAM Rate Surcharge	0.34		0.51		0.29	॥	Line 9 divided by Line 1
13	Total	7.19		10.79		6.01	॥	Line 11 + Line 12
							॥	
14	RAM Percent Rate Increase (after decoupling	5.0%		5.0%		5.0%	॥	Line 12 divided by Line 11
							॥	
							॥	
Immediate New Rate Case							॥	
15	Electric Sales Used for Rate Design (MWh)	7,300,000		1,800,000		5,500,000	॥	From Attachment 1, Line 21
				25%		75%	॥	
							॥	
	Base Revenue Requirements Determination						॥	
16	Revenue Requirements from Prior Case	500,000					॥	From Attachment 1, Line 2
17	RAM Equivalent Increase in Revenue Req	25,000					॥	Assumes add'l rev req = RAM adj
18	New Base Revenue Requirements	525,000					॥	Line 16 + Line 17
							॥	
	Cost of Service Proxy Allocation						॥	
19	Sales Allocation	100%		25%		75%	॥	Line 15
20	Ratio Fixed Costs/Sales Allocation			1.39		0.86	॥	From Attachment 1, Line 8
21	Fixed Costs (Combined Demand & Customer)			34%		66%	॥	Line 19 x Line 20
							॥	
	New Base Revenue Requirements ($000)						॥	
22	Customer Class Allocation ($000)	525,000		179,615		345,385	<=	Line 21 x line 22
								Rate case results differ substantially
23	New Base Rates (¢/KWh)	7.19		9.98		6.28		from decoupling and RAM results.
								[Line 22 differs from Line 10]
24	Difference -- Rate Case vs Uniform Surcharge	0.00		(0.81)		0.27		
	(¢/KWh)							
	Percent Difference			-8%		4%		

Attachment 4

Customer Class Allocation of Sales Decoupling and RAM Rate Adjustments Rate Case Approximation Method

Illustrative Example

Line Number		Total Company	Residential	Non-Residential		Comments
Annualt RAM Rate Adjustment -- Different Class Sales Levels (Uniform per KWh Surchage Method)						
1	Actual Electric Sales (MWh)	7,300,000	1,800,000	5,500,000		From Attachment 2, Line 9
	Rate Adjustment Mechanism ($000)					
2	O&M Expense Increase	5,000				Consistent with HECO/CA
3	Rate Base Related Adjustment	20,000				illustrative RAM calculations for 2010
4	Total RAM Revenue Adjustment	25,000				
	Allocation of RAM Rate Adjustment					
5	RAM Revenue Adjustment ($000)	25,000				
6	New Sales Level (MWh)	7,300,000				
7	RAM Rate Surcharge (¢/KWh)	0.34	0.34	0.34		Line 5 divided by Line 6 and applied to each rate class
8	RAM Revenue Increase ($000)	25,000	6,164	18,836		Line 7 x Line 1
	Revised Class Revenues ($000)					
9	Base Revenues After Decoupling	500,000	171,062	328,938		From Attachment 2, Line 16
10	RAM Revenue Increase ($000)	25,000	6,164	18,836		Line 8 + Line 9
11	Total	525,000	177,226	347,774	<=	Line 9 + Line 10
					ll	
	New Customer Rates (¢/KWh)				ll	
12	Total Rate after Decoupling	6.85	9.50	5.98	ll	From Attachment 2, Line 17
13	RAM Rate Surcharge	0.34	0.34	0.34	ll	Line 10 divided by Line 1
14	Total	7.19	9.85	6.32	ll	Line 12 + Line 13
					ll	
15	RAM Percent Rate Increase (after decoupling	5.0%	3.6%	5.7%	ll	Line 13 divided by Line 12
					ll	
					ll	
Immediate New Rate Case					ll	
16	Electric Sales Used for Rate Design (MWh)	7,300,000	1,800,000	5,500,000	ll	From Attachment 2, Line 21
			25%	75%	ll	
					ll	
	Base Revenue Requirements Determination				ll	
17	Revenue Requirements from Prior Case	500,000			ll	From Attachment 2, Line 2
18	RAM Equivalent Increase in Revenue Req	25,000			ll	Assumes add'l rev req = RAM adj
19	New Base Revenue Requirements	525,000			ll	Line 17 + Line 18
					ll	
	Cost of Service Proxy Allocation				ll	
20	Sales Allocation	100%	25%	75%	ll	Line 16
21	Ratio Fixed Costs/Sales Allocation		1.39	0.86	ll	From Attachment 2, Line 8
22	Fixed Costs (Combined Demand & Customer)		34%	66%	ll	Line 21 x Line 20
					ll	
	New Base Revenue Requirements ($000)				ll	
23	Customer Class Allocation ($000)	525,000	179,615	345,385	<=	Line 23 x line 22
						Rate case results are equivalent to
24	New Base Rates (¢/KWh)	7.19	9.98	6.28		decoupling and RAM results.
						[Line 23 is equivalent to Line 11]
25	Difference -- Rate Case vs Uniform Surcharge (¢/KWh)	0.00	0.13	(0.04)		
	Percent Difference		1%	-1%		

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF HAWAII

In the Matter of PUBLIC UTILITIES COMMISSION Instituting a Proceeding to Investigate Implementing a Decoupling Mechanism for Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., and Maui Electric Company, Limited	DOCKET NO. 2008-0274

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on this date a copy of the foregoing document was duly served upon the following individuals by placing a copy of same in the United States Mail, postage prepaid, and/or by electronic service, as follows:

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